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Public Service Commission of Wisconsin
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**BEFORE THE
PUBLIC SERVICE COMMISSION OF WISCONSIN**

Joint Application of American Transmission Company LLC and Northern States Power Company–Wisconsin, as Electric Public Utilities, for Authority to Construct and Operate a New 345 kV Transmission Line from the La Crosse area, in La Crosse County, to the greater Madison area in Dane County, Wisconsin	Docket No. 5-CE-142

REVISED DIRECT TESTIMONY OF PETER LANZALOTTA IN OPPOSITION TO THE APPLICATION (REDACTED COPY)

Q. Please state your name, position and business address.

A. My name is Peter J. Lanzalotta. I am a Principal with Lanzalotta & Associates LLC, ("Lanzalotta"), 67 Royal Point Drive, Hilton Head Island, SC 29926.

Q. On whose behalf are you testifying in this case?

A. I am testifying on behalf of intervenors Citizens Energy Task Force, Inc. and Save Our Unique Lands of Wisconsin, Inc. ("CETF/SOUL").

Q. Mr. Lanzalotta, please summarize your educational background and recent work experience.

A. I am a graduate of Rensselaer Polytechnic Institute, where I received a Bachelor of Science degree in Electric Power Engineering. In addition, I hold a Masters degree in Business Administration with a concentration in Finance from Loyola College in Baltimore.

I am currently a Principal of Lanzalotta & Associates LLC, which was formed in January 2001. Prior to that, I was a partner of Whitfield Russell Associates, with which I had been associated since March 1982. My areas of expertise include electric system planning and operation. I am a registered professional engineer in the states of Maryland and Connecticut.

In particular, I have been involved with the planning and operation of electric utility systems as an employee of and as a consultant to a number of privately- and publicly-owned electric utilities over a period exceeding thirty years.

I have presented expert testimony before the FERC and before regulatory commissions and other judicial and legislative bodies in 25 states, the District of Columbia, and the Provinces of Alberta and Ontario. My clients have included utilities, state regulatory agencies, state ratepayer advocates, independent power producers, industrial consumers, the United States Government, environmental interest groups, and various city and state government agencies.

A copy of my current resume is included as Ex.-CETF/SOUL-Lanzalotta-1 and a list of my testimonies is included as Ex.-CETF/SOUL-Lanzalotta-2.[1]

Q. What is the purpose of your testimony?

A. I was retained to review and comment on the need for the Badger-Coulee Project, and on the benefits and issues attributed to the Badger-Coulee Project and as compared to potential alternatives.

Q. What documents have you reviewed as part of your investigation?

A. I have reviewed i) testimonies, studies, and discovery responses by the Applicants, ii) various documents in the CapX2020 Wisconsin regulatory proceeding documents, iii) testimony, studies, analyses by MISO regarding the MVP Projects and regarding system planning, iv) various other documents such as strategic energy assessments and other publicly-available reporting and planning documents relevant to the use of and supply of electric power in Wisconsin.

Q. What conclusions do you reach regarding the need for and the benefits attributable to Badger-Coulee?

A. I conclude that there is little current reliability need for Badger-Coulee that cannot be addressed by reinforcements to lower voltage transmission facilities, but that this minimal need is greatly reduced by the current and projected lack of load growth. I further conclude that there has been no study of the expected benefits from Badger-Coulee under

[1] Exs.-CETF/SOUL-Lanzalotta-1–4 are attached to and incorporated by reference in this testimony.

no load growth conditions, or under conditions of negative load growth in the near term. The benefits from Badger-Coulee decrease as the assumed rate of peak load growth decreases, but all of the scenarios studied assume some rate of positive load growth. It is not possible to say what levels of benefits, if any, would be likely under zero or negative load growth scenarios. It is possible to say that the reliability benefits from Badger-Coulee, compared to a low voltage alternative, would be minimized under no growth or negative growth conditions, since system loadings would not be increasing in most cases, and might even be decreasing. Under these conditions, I do not believe that approval of the Badger-Coulee project is warranted.

Q. What kind of benefits can new transmission facilities bring to an electric system?

A. Among the most prevalent benefits usually expected from new transmission facilities are i) satisfying reliability requirements, ii) providing economic benefits, and iii) providing public policy benefits.

Reliability requirements arise from transmission planning criteria promulgated by NERC and by others. These criteria typically look at the performance of the transmission system with all components in service,[2] and with various components out of service, either because of planned outages or because of forced outages, frequently called contingencies.

Economic benefits can include access to lower-cost power, reducing system congestion, reduced system losses, the value of reliability increases above minimum requirements, among others.

Public policy benefits can include helping to meet policy goals, such as using more renewable generation.

[2] Components typically include transmission lines, substation transformers, generating units, and other major system components.

Q. What benefits are attributed to the Badger-Coulee project by the Applicants?

A. The revised Application, under the heading "Project Need and Engineering" [3] it states:

> The primary reason for constructing the Project is economic – the reduction it will provide in the cost of electricity for Wisconsin ratepayers, together with other cost savings it will produce for Wisconsin, more than offsets the charge to Wisconsin ratepayers for constructing the line. This cost benefit will be produced regardless of which one of a wide range of possible future economic scenarios actually occurs. In addition to the cost savings, the Badger Coulee line provides reliability benefits for the La Crosse area by adding a second transmission source to serve growing load and for Western Wisconsin by reducing the load on the lower voltage system. Further, the line provides public policy benefits by facilitating the use of renewable energy, helping to avoid construction of additional generation facilities in Wisconsin, and reducing congestion on the transmission system.

The Applicants attribute economic benefits, reliability benefits, and public policy benefits to the Badger-Coulee Project. They have performed an evaluation of the Project under what they call "a wide range of possible future economic scenarios" to show that there are economic benefits.

Q. Does the Applicants' contention above mean that the cost benefit from Badger-Coulee will be produced regardless of what future economic scenario actually occurs?

A. No. The Applicants' contention only addresses the range of scenarios that were actually evaluated for Badger-Coulee. All of the scenarios actually evaluated assume some level of future load growth. As addressed in the direct testimony of William Powers, also on behalf of CETF/SOUL, however, loads have been declining in the ACTW service area as of late, and are not projected to increase materially in the coming years. None of the

[3] Revised CPCN Application (PSC Ref. # 204860), p. 36 (as cited in Ex.-Applicants-Henn-1 (PSC Ref. # 226510), p. 2).

scenarios evaluated by the Applicants looked at zero load growth or negative load growth.

Q. What effect does lowering the assumed future load growth rate have on the benefits attributed to Badger-Coulee by the Applicants?

A. In general, lower future load growth rates result in lower benefits from the high voltage transmission option of the Badger-Coulee proposal. This is reflected in Table 1 below, the data in which comes from Revised Appendix D.[4]

Table 1

Annual PROMOD Energy Savings Attributable To Badger Coulee in 2020						
Scenario	Robust Economy	Green Economy	Slow Growth	Regional Wind	Limited Investment	Carbon Constrained
Load Growth (%)	2.50%	1.40%	0.20%	1.70%	1.00%	0.20%
ATC Benefit ($M)	18.87	9.34	2.61	6.98	7.65	5.75

The two scenarios with the lowest growth rates, the Slow Growth scenario and the Carbon Constrained scenario, also have the lowest level of energy savings attributable to Badger-Coulee. If this study had been done with a 0% growth rate, or the current projected growth rate of 0.03% between 2012 and 2020 based on utility data in support of the 2020 Wisconsin Strategic Energy Assessment ("SEA"), I would expect the energy savings attributable to Badger-Coulee to be even lower, especially under economic conditions where electric rates are increasing, improvements in appliance and building

[4] (REDACTED COPY) Application Appendix D, Exhibits 1 and 2 Updated (PSC Ref. # 204738), pp. 38, 41 (as cited in Ex.-Applicants-Henn-1 (PSC Ref. # 226510), p. 4).

codes are taking hold, and interest in distributed generation is increasing due to environmental and economic benefits.

Q. What about the Carbon Constrained scenario as a plausible future scenario?

A. The Carbon Constrained scenario assumes a renewable power standard ("RSP") more than double what is currently in effect, increasingly stringent environmental regulations, and the highest feasible level of retirements of smaller, older coal plants within ATC and 350MW of distributed renewable generation within Wisconsin's footprint.[5] The low load growth rate in this scenario in ATC's studies is not attributable to a sluggish economy, but rather reflects increased investments in demand reduction and energy efficiency. If these increased investments in demand reduction and energy efficiency were applied to a future with zero percent projected load growth rate, the resultant rate of growth would be negative. So, to be comparable to a Slow Growth scenario, or the SEA, with little or no projected load growth, the Carbon Constrained scenario should reflect a negative future load growth rate, to reflect these increasingly strict environmental regulations being added on top of the projected zero load growth in ATC's service area, thereby further reducing the estimated benefits from Badger-Coulee.

Q. What if economic benefits other than energy savings are included? Does a slow growth scenario still show lower economic benefits for Badger-Coulee than any of the other scenarios examined?

A. Yes. Table 2 below shows the total economic benefits attributed to Badger-Coulee over 40 years under the various scenarios studied by the Applicants. The growth rates for each scenario are the same as those shown in Table 1.

[5] *Id.* at pp. 36, 38–39.

Table 2

Present Value of Aggregate Economic Benefits from Badger Coulee ($M - 2012)						
Scenario	Robust Economy	Green Economy	Slow Growth	Regional Wind	Limited Investment	Carbon Constrained
ATC Benefit	750.98	711.98	130.54	608.79	382.50	520.53

Under a slow growth scenario with a projected growth rate of 0.2%, the Badger-Coulee economic benefits are considerably smaller than any other scenario studied, and are less than half the benefits of the scenario with the next lower level of economic benefits. This low 0.2% growth rate is also seen in the SEA if loads projected for 2020 are compared to 2011 load data, as compared to a 0.03% growth rate for the period 2012 – 2020. If a low growth scenario with a zero percent rate of load growth were to be studied, it is reasonable to expect that these benefits would be lower still. Without such a scenario, it's not clear what level of economic benefits, if any, are likely to result from Badger-Coulee under current economic and policy conditions.

It is helpful to put the $130.54 million of potential slow growth benefits from Table 2 of total 40 year present value benefits from Badger-Coulee into perspective. For the slow growth scenario over 40 years and for the approximately 3 million Wisconsin retail electric customers,[6] this reflects an average benefit of $1.10 per customer per year or about 9 cents per customer per month. As requested by numerous municipalities and ratepayers,[7] a clearer picture of the value of all potential benefits could be obtained from

[6] 2,955,636 in Table 9, EIA 2012 Retail Electric Sales Statistics.

[7] Resolutions adopted by more than 90 municipal governments from across Wisconsin are posted on the docket and are listed in Table G.1-1 of the EIS. The resolutions ask for comprehensive cost-benefit analysis based on the

comprehensive cost-benefit analysis including comparable investments in no wire solutions such as energy efficiency and improvements to the low voltage system. Mr. William Powers is examining strategically locating distributed renewable power to extend the life of the aging low voltage facilities.

Q. **The Applicants also performed an analysis of customer energy cost benefits from Badger-Coulee using MTEP 13 load growth assumptions. Does a slow growth scenario still show lower economic benefits for Badger-Coulee than any of the other scenarios examined?**

A. Yes. Table 3 below summarizes the customer energy cost benefits from Badger-Coulee using MTEP 13 long-term peak load growth assumptions of 0.22% per year for a low growth scenario, 0.75% per year for a business as usual scenario, and 1.25% per year for a robust economy scenario.

Table 3

Badger Coulee Energy Cost Savings - MTEP 13 Futures			
Scenario	Low Growth	Business as Usual	Robust Economy
Load Growth (%)	0.22%	0.75%	1.25%
2023 Savings ($M - 2023)	1.98	2.50	7.38
2028 Savings ($M - 2023)	1.68	4.10	10.27
40 Year PV Savings ($M - 2023)	19.70	39.86	103.89

collective costs that would be assumed by Wisconsin ratepayers for all of the high capacity transmission projects announced by utilities and including comparisons of CO2 emission reduction, job creation and other impacts. More than 2000 persons have signed petitions asking the PSC to insure that the cost-benefit analysis requested by the municipal governments be conducted as part of this utility case.

As was the case for the savings summarized in Tables 1 and 2 above, the lower the rate of load growth, the lower the energy cost savings estimated for Badger-Coulee. If a low growth scenario with a zero percent rate of load growth were to be studied, it is reasonable to expect that these benefits would be lower still. Without such a scenario, it's not clear what level of economic benefits, if any, are likely to result from Badger-Coulee under current conditions.

It is worth noting that the 0.22% limited growth load growth rate used in the MTEP 13 analysis was higher than the 0.20% load growth rate that was used in the Revised Appendix D calculations for a slow growth scenario, as reflected in my Table 1. Hence, the application of MTEP 13 futures to the analysis of Badger-Coulee benefits actually increases by 10% the demand growth rate applied to limited growth conditions over what was used in Ex. Henn-1-3 (Citing PSC Ref. # 204738c).

Q. **What are the implications of projected zero percent load growth from a transmission planning perspective?**

A. If loads do not grow, then reliability problems do not develop over time, all else equal. The current ATC system meets NERC transmission planning standards, which are mandatory. If loads do not grow, then facilities that are not overloaded now do not become overloaded in the future. Also, if today's system meets voltage and stability standards, this is not likely to substantially change in the future under a zero percent low load growth scenario which assumes minimal changes in loads and resources.

Another implication of projected zero percent load growth involves the fact that there is an alternative to the high voltage transmission option of Badger-Coulee included in this proceeding which involves the use of targeted upgrades and additions to lower voltage[8] transmission facilities and which is referred to as the Low Voltage ("LV") option. A major part of the economics of the LV option is the cost of upgrading existing transmission facilities. With no load growth, the need for these upgrades would disappear, or, with minimal load growth, be pushed even farther out into the future than they are now, thus lowering the cost for the LV option as compared to what was modeled by the Applicants, as addressed in the testimony of William Powers.

Also, a no load growth or very low load growth scenario provides favorable conditions for the consideration of cost effective non-transmission alternatives in place of transmission system reinforcements as discussed in the direct testimony of William Powers.

The Commission should insist on the use of zero percent future load growth rate scenario and a 0.03 percent future load growth rate scenario, at a minimum, to help evaluate i) both the likelihood of economic benefits from Badger-Coulee under current and forecast conditions as compared to the LV option, and ii) to get a more realistic evaluation of the transmission reinforcements needed for reliability purposes under the LV option. It would be prudent to look at a negative growth scenario, as well.

Q. What are the likelihoods of no load growth or even negative load growth?

A. Load growth among the Applicants has generally been pretty flat. NSPW's 2013 load was less than its load in 2006 and 2007, while ATC's system peak in 2103 was only 48 MW above its 2003 peak of 12,708.

[8] Lower than the 345 kV voltage of Badger-Coulee.

Also, WI electric customers pay average electric rates that are among the highest in the Midwest with increases attributed to lower use and prior investment transmission.[9] Renewable and distributed generation and energy storage technologies are quickly becoming more reasonably priced and more capable as a replacement to buying electricity. The higher that electric rates in Wisconsin go, the easier it is for alternative generation sources to compete with the incumbent suppliers. It is not clear what the costs for and capabilities of renewable and distributed generation and energy storage will be in even five or ten years, if not sooner. But, it is clear that the supply and demand sides of the utility business are in a state of change and development. At this point, when trying to predict costs and benefits of various facilities over a period of 40 years, it seems unwise to completely discount any possibility. This is especially true given the lack of rigor in considering non-wires alternatives, which William Powers addresses in his testimony on behalf of CETF/SOUL.

Q. How does the cost of the LV option compare with the cost to build Badger-Coulee?

A. As presented in Henn-1, The LV option has a total project cost of $428.7 million, compared to the Badger-Coulee cost of about $580 million. The cost for the LV option was reduced by the Applicants to $404.1 in responses to discovery. Additionally, the Applicants provided a list of LV projects based on an updated analysis using MTEP13 data, in response to discovery, in which the LV upgrades required under a LV alternative were estimated to cost only $218.9 million.

Of course, these LV costs reflect higher load growth, and presumably, higher costs, than a zero percent annual load growth scenario, which is probably the most realistic scenario,

[9] Ex.-CETF/SOUL-Lanzalotta-3, p. 39, Table 8.

given the forecasts referenced in the testimony of William Powers. At zero percent load growth, or even near-zero percent load growth, the need to reinforce low voltage facilities would be deferred or even eliminated compared to the Applicants' studies.

It should also be noted that a number of the lower voltage facilities to be upgraded under the LV option are old and would likely need rebuilding within the foreseeable future and certainly within the 40 year evaluation period used by the Applicants. Service lives for older transmission lines of 50-60 years are relatively common. [redacted]

Q. Do you have any other comment about the economic benefits studies?

A. Yes. When considering the economic benefits for large bulk power electric system additions, such as Badger-Coulee, the expense of the line is incurred before the line goes into service, while the economic benefits, if any, are spread over many decades following the in-service date. The economic benefits attributed to Badger-Coulee by the Applicants are estimated generally over a 40 year period. Now, 40 years is a long time over which to try to predict electric loads on the system, or economic benefits attributable to various capital additions. Any difference in the underlying assumptions when estimating economic benefits over 40 years only has to have a small effect per year to produce benefits large enough over 40 years to justify big system additions. This makes it even more imperative to use realistic study assumptions and to capture the likely impact of technological advances. The Applicants' failure to even consider conditions of zero or negative load growth as sensitivity scenarios means we really don't know the range of economic benefits outcomes that are possible, or even likely.

Q. Other than economic benefits, the Applicants also claim that Badger-Coulee will reduce congestion on the transmission system. Please comment.

A. According to an ATC review in early 2014 of the length and severity of congestion on the ATC system, as measured by what ATC calls their Congestion Severity Index ("CSI").[10] The CSI measures the severity of constraints by determining the theoretical maximum cost of constraints, in millions of dollars. This value is referred to as the CSI. Table 4 below shows the annual CSI for the Day-Ahead and Real-Time markets for each year from 2008 to 2013.

Table 4

ATC Congestion Severity Index (CSI) History		
Year	Day Ahead CSI	Real Time CSI
2008	179.31	179.89
2009	116.39	110.23
2010	109.19	111.68
2011	91.27	78.19
2012	71.02	54.80
2013	66.90	53.31

[10] http://www.atc10yearplan.com/selected-planning-initiatives/economic-planning/#events-2014.

Table 4 shows that both Day ahead and Real-time CSIs have decreased every year over the last three years and have decreased in most years since 2008. The 2013 CSI for the day-ahead market, at 66.90, is less than 40% of the comparable 2008 CSI (179.31), while the 2013 CSI for the real-time market, at 53.31, is less than 30% of its comparable 2008 CSI (179.89). By these measures, 2013 day ahead congestion on the ATC system has dropped by more than 60% since 2008, while 2013 real time congestion has dropped by more than 70% since 2008.

These numbers indicate that loading of the transmission system during high load periods is decreasing, the cost of power during these periods is dropping, or some combination of the two. And, as long as load growth stays flat or negative, there is little reason to expect any increase in congestion. Also, given that transmission system congestion also can increase due to increased power flows across a transmission system, the drop in CSI indicates a drop in such transfers or an increase in the current system's ability to handle such transfers.

Q. The Applicants' Application credits Badger-Coulee with providing reliability benefits for the La Crosse area by adding a second transmission source to serve growing load. Please comment.

A. The addition of an additional transmission source to any area will provide reliability benefits. But, an additional transmission line has costs. That's one reason why NERC has mandatory transmission planning criteria that specify the reliability conditions under which system reinforcement is needed. NERC requires that the transmission be planned so that i) under normal conditions, with all facilities in service, transmission lines and substation transformers are not overloaded and substation busses have voltage levels within acceptable normal ranges and ii) under specified contingency conditions with some facility or facilities out of service, the remaining in-service facilities are loaded within emergency ratings and voltages are within emergency ranges.[11] When transmission planning shows that facilities overload or voltages fall outside the required ranges under normal or under specified contingency conditions, this is typically referred to as a NERC violation, and NERC requires that some system reinforcement, or other remedy, be implemented.[12]

When the PSCW Staff asked the Applicants about whether the added reliability from Badger-Coulee to the La Crosse area was needed to address a NERC violation, the Applicants responded:

> Yes. When the local load in the La Crosse/Winona area reaches 750 MW, an additional line and a second Briggs Road 345 kV/161 kV transformer will be necessary to address NERC Category C contingencies, specifically, TPL-003, loss of a generator in the area and the CapX2020 345 kV line into Briggs Road Substation. This peak demand level is expected to be reached in the area between 2025 and 2040 depending on how load develops in the area. Applicants note that peak demand in the La Crosse/Winona area has increased each year since 2009.[13]

Applicants include a table in the response showing the sum of the NSPW and DPC non-coincident peak loads in the La Crosse-Winona area from 2009 to 2013, with a load of 490.4 MW in 2013.

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[11] Typically, no firm load shedding is permitted under most single contingencies.

[12] A reduction in load level can usually help alleviate overloads and voltage problems.

[13] Ex.-Applicants-Henn-2 (PSC Ref. # 226551), p. 5, Response No. 1.30 (PSC Ref. # 197626).

The loads from 2009 to 2013 reflect about a 3.0% annual growth rate in load.[14] If these loads were to maintain this 3% growth rate, then the sum of the non-coincident peaks would reach 750 MW by 2028, some 14 years in the future. Of course, simply adding non-coincident peak loads will overstate the annual peak loads if the non-coincident peaks occur at different times. As discussed in the testimony of William Powers, in prior years, intervenors in transmission line cases have alleged that 5% diversity or more exists between these non-coincident peaks. Should this still be the case, then it could take an additional year or more than this to reach 750 MW. This would put this reliability need for Badger-Coulee 15 or more years in the future. This not only puts this reliability need outside the typical 10 year planning horizon, but it also provides time to implement non-transmission alternatives, as addressed in the testimony of William Powers.

The Applicants' estimated potential date of 2025 for the total of the non-coincident peaks in the La Crosse Winona area to reach 750 MW reflects a 3.45% annual growth rate, a level which was reached or slightly exceeded twice in the period from 2009 to 2012. (In 2013, this growth rate dropped to below 2%.)

Also, as addressed in the testimony of William Powers, had ATC compared noncoincident peak load in 2006 and 2011, it would have concluded that there was no peak load growth in the La Crosse/Winona area over time, instead of 3.44 percent per year, and had 2006 to 2012 noncoincident peak load been compared it would have determined the rate of peak load growth was less than 0.5 percent per year.

Considering that the La Crosse Winona area could not even maintain a 3.45% level of growth for the five year period from 2009 to 2013, it seems unlikely that it would

[14] See Ex.-CETF-Lanzalotta-3 for various load growth rate calculations regarding LaCrosse.

maintain this level of growth for the eleven years or longer that it would take these loads to total to 750 MW. Diversity between the non-coincident peak loads could push this out to twelve years or more. As before, this puts this reliability need outside the typical 10 year planning horizon, and it also provides time to implement non-transmission alternatives, as addressed in the testimony of William Powers.

Q. The Applicants included the Western Wisconsin Transmission Reliability Study ("WWTRS"), dated September 20, 2010 as an Addendum to the Badger Coulee Planning Analysis. Please comment.

A. The WWWTRS was prepared to assess the reliability needs of Western Wisconsin and to compare alternatives to satisfy those needs. It was based on MTEP08, a MISO system planning study completed in late 2008. This means that the WWTRS used peak demand growth rates that are unrealistically high by today's perspective.

In MTEP08, the Western division of MISO, which includes Wisconsin, had peak demands that were forecast to grow 1.9% annually for the next ten years, while all of MISO was projected to grow at 1.5% over the same period.[15] These load growth rates were used in the WWTRS.[16]

In MTEP 2009, the ten year peak load growth rate for total MISO was projected to drop to 1.1%.[17]

[15] https://www.misoenergy.org/Library/Repository/Study/MTEP/MTEP08/MTEP08%20Report.pdf, pp. 40 (Table 3.2-1) and 41 (Table 3.2-2).

[16] See Ex.-CETF/SOUL-Lanzalotta-4 for all MTEP-related load growth rate calculations.

[17] https://www.misoenergy.org/Library/Repository/Study/MTEP/MTEP09/MTEP09%20Report.df; p. 72 (Figure 5.1-5).

In MTEP 2010, the ten year peak load growth rate for total MISO for the existing members was projected to drop to 0.9%, while new members with ten year peak load growth rates of 3.9% were added to MISO that brought this rate back up to 1.1%. MTEP2010 also forecasted a 1.04% ten year peak load growth rate for West MISO, which was a drop from 1.9% just two years earlier. This is a drop of about 45%[18].

In MTEP 2011, the ten year peak load growth rate for total MISO dropped again to about 0.95%[19]. In MTEP 2012, this annual forecast rate was increased slightly, to about 1.1%, while actual MISO 2013 peak load dropped by about 2.5% from the previous year.[20] [21]

The rates of load growth used in the WWTRS are so much higher than what is actually happening, that many of the contingency effects modeled in the WWTRS for 2014 and 2018 would be different, and some may not even occur, because projected loads using a realistic rate of growth would be lower than modeled.

The high rates of load growth used in the WWTRS also assume higher amounts of wind development and greater amounts of base-load power transfer than if loads were not growing. These high levels of transfers also affect system stability performance. In general, the more of an area's load that is served from distant generators over large high voltage transmission lines, the more likely system stability problems are to appear during required transmission planning. One reason is that, there can be so much power flowing over such a line that, when it trips out unexpectedly, there is a lot of power flow to

[18] https://www.misoenergy.org/Library/Repository/Study/MTEP/MTEP10/MTEP10%20Report.pdf, p. 75 (Tables 5.2-1 and 5.2-2).

[19] https://www.misoenergy.org/Library/Repository/Study/MTEP/MTEP11/MTEP11%20Report.pdf, page 96 (Table 5.2-2).

[20] https://www.misoenergy.org/Library/Repository/Study/MTEP/MTEP12/MTEP12%20Report.pdf, page 72 (Table 6.2-3).

[21] Ex.-Applicants-Henn-2 (PSC Ref. # 226551), p. 22, Response 1.151 (PSC Ref. # 200029).

suddenly be rerouted to other lines and generating units. This effect is intensified if it occurs during lighter load periods.

If the Applicants want the WWTRS to be relevant to today's electric system needs, it would have to be updated for the low or non-existent levels of load growth currently expected. The impact of rapid expansion of solar generation, energy efficiency, and demand response would also need to be accounted for in both the performance evaluation and the determination of energy policy.

Q. The Direct Testimony of Laura Rauch, on behalf of MISO, describes the reliability analyses performed by MISO.[22] Please comment.

A. The referenced testimony describes that MISO performed a steady state analysis of thermal loading and voltages, as well as system stability studies. The purpose was to identify reliability issues that will occur if Badger-Coulee is not built. However, the benefits studies, MISO's studies are based on peak load growth assumptions that are too high in light of current conditions.

The MVP portfolio of transmission projects, of which Badger-Coulee is a part, were approved in December, 2011 as part of MISO's MTEP 11.[23] The 2011 studies supporting the MVP projects used growth rates of 1.26% for a low growth business as usual scenario and 1.86% for a high growth business as usual scenario.[24] However, in MTEP 11, the ten year peak load growth rate for net internal demand was about 0.95%, considerably lower than what was used for the MVP studies. This is the rate used for system planning and

[22] Direct-MISO-Rauch-25.

[23] *Id.* at 9.

[24] (PSC Ref. # 218122), p. 15.

resource adequacy determinations. Using these higher load growth rates helped increase loadings on transmission facilities and provide additional justification for the MVP projects, including Badger-Coulee. MISO's current Triennial Review of the MVP projects reduces the business as usual ten-year peak load growth to 1.06%[25], which is still too high, at least from the perspective of Western Wisconsin. And, as above, the impact of rapid expansion of solar generation, energy efficiency, and demand response would also need to be accounted for.

Q. **The Direct Testimony of Laura Rauch states that the MISO analyses identified numerous reliability issues that will occur if Badger-Coulee is not built.[26] Please comment.**

A. Given the 1.26% and 1.86% long term peak demand growth rates used by MISO, without some sort of system reinforcement, overloads and other reliability problems are typically considered normal. If zero load growth or very low load growth, such as 0.2%, had been used, there would no doubt be significant changes in the number, the timing, and the severity of these violations.

Q. **Laura Rauch describes the low voltage alternative that MISO considered, and why it was rejected[27]. Please comment.**

A. MISO rejected the low voltage alternative because of cost. Of course, this cost was inflated because the very high load growth rates used in the study provided for more

[25] *Id.* at 15.

[26] (PSC Ref. # 218119), p. 25.

[27] *Id.* at 29.

overloaded facilities than would a zero load growth rate or a very low rate of load growth.

Q. The 2014 Triennial Review of the MVP Projects states that congestion and fuel savings are the most significant part of the MVP benefits[28]. Please comment.

A. As shown in Table 3 earlier in this testimony, ATC's congestion severity index ("CSI"), a measure of the value of congestion on the transmission system, has been decreasing substantially since 2008 through 2013. From 2011, when the MVP projects were initially studied, to 2013, ATC's day-ahead CSI has decreased by more than 25%, and its real-time CSI has decreased by more than 30%. There is no guarantee that other parts of the transmission system in MISO are experiencing declines in congestion such as ATC is experiencing. But, the large declines in congestion on the ATC system without an MVP project certainly raises questions as to whether the MVP projects are necessary to reduce congestion, at least where ATC and Badger-Coulee are concerned.

Q: Given your analysis of the costs and benefits of this proposal, the timing of this proposal and the fact that utilities have announced interests in additional, potentially connected high capacity transmission systems in Wisconsin, could this be a particularly pivotal energy decision for the state?

A: I think it is reasonable to infer that the decision will be unusually influential. Given the slow and/or negative growth conditions, and the rising interest in distributed solar and accelerated energy efficiency, should the ratepayers and the PSC not be ready to move forward with full confidence, a wise investor would probably pause at least a few years to see which trends truly develop.

[28] (PSC Ref. # 218122), p. 26.

Q. Does this conclude your testimony?

A. Yes at this time.